EXHIBIT NO. ___(DEM-11CT)
DOCKET NOS. UE-111048/UG-111049
2011 PSE GENERAL RATE CASE
WITNESS: DAVID E. MILLS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-111048** **Docket No. UG-111049**

PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS
ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED VERSION

JANUARY 17, 2012

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Are you the same David E. Mills who provided in this proceeding prefiled direct testimony, Exhibit No. ___(DEM-1CT), on June 13, 2011, and prefiled supplemental testimony, Exhibit No. ___(DEM-8T), on September 1, 2011, each on behalf of Puget Sound Energy, Inc. ("PSE")?

A. Yes.

Q. What is the purpose of this prefiled rebuttal testimony?

A. This rebuttal testimony responds to the various power cost adjustment proposals included in the testimonies of:

- Mr. Alan P. Buckley and Mr. Roland C. Martin, witnesses for the Staff of the Washington Utilities and Transportation Commission ("Commission Staff"), Exhibit No. ___(APB-1CT) and Exhibit No. ___(RCM-1T), respectively;
- Mr. Michael C. Deen and Mr. Donald Schoenbeck, witnesses for the Industrial Customers of Northwest Utilities ("ICNU"), Exhibit No. ___(MCD-1CT) and Exhibit No. ___(DWS-1CT), respectively; and
- Ms. Andrea C. Crane, witness for the Public Counsel section of the Washington State Attorney General's Office ("Public Counsel"), Exhibit No. ___(ACC-1T).

First, this prefiled rebuttal testimony discusses Commission Staff and ICNU's proposals to move costs out of baseline rates and into PSE's power cost adjustment ("PCA") mechanism.

Second, this prefiled rebuttal testimony addresses the following power cost adjustments proposed by Commission Staff, ICNU and Public Counsel:

(i) adjustments proposed by Commission Staff and ICNU to reduce costs PSE incurs to integrate its wind resources on a day-ahead basis, also known as day-ahead wind integration costs;

(ii) an adjustment proposed by Commission Staff to reduce costs PSE incurs to integrate its Wild Horse Wind Project ("Wild Horse");

(iii) adjustments proposed by Commission Staff and ICNU to reduce costs associated with PSE's rate year natural gas for power hedges;

(iv) an adjustment proposed by Commission Staff to remove some of the contract costs of gas from the Cedar Hills facility;

(v) an adjustment proposed by ICNU to reduce costs associated with PSE's gas pipeline costs;

(vi) an adjustment proposed by ICNU to reduce costs associated with PSE's winter peak planning;

(vii) an adjustment proposed by ICNU to reduce other power costs reflected in Federal Energy Regulatory Commission ("FERC") account 557;

(viii) an adjustment proposed by ICNU to adjust the AURORA model inputs to reflect more recent operations for several of PSE's combined-cycle units – Goldendale, Mint Farm and Sumas;

(ix) an adjustment proposed by ICNU to reflect the most recent twelve months of actual revenues associated with sales of excess transmission;

(x) an adjustment proposed by Commission Staff to remove the costs associated with 23 megawatts ("MW") of transmission capacity;

(xi) an adjustment proposed by ICNU to reduce costs associated with PSE's contract with the Public Utility District No. 1 of Chelan County, Washington ("Chelan PUD") for its share of the hydroelectric output from the Rocky Reach and Rock Island Hydroelectric Projects;

(xii) an adjustment proposed by Public Counsel to adjust amortization expense for PSE's prepayment related to the capacity reservation charge associated with the new Chelan PUD contract;

(xiii) an adjustment proposed by Commission Staff to reduce the amortization expense associated with the Colstrip Units 1 & 2 coal contract;

(xiv) an adjustment proposed by Commission Staff to increase the transmission credits related to the Lower Snake River Wind Project;

(xv) an erroneous adjustment included in ICNU's power costs that is based on a single water year Aurora run instead of the 70 water year run; and

(xvi) an adjustment proposed by Commission Staff and ICNU to update the rate year power costs with the most recent gas prices available prior to the implementation of this proceeding's general rate change.

Third, this prefiled rebuttal testimony summarizes the following production operations and maintenance ("O&M") cost adjustments proposed by Commission Staff and ICNU that will be discussed in detail in the Prefiled Rebuttal Testimony of Mr. Wayne R. Gould, Exhibit No. ___(WRG-1T), including:

(i) an adjustment proposed by ICNU to reduce production O&M costs for PSE's Frederickson Units 1-2, Fredonia Units 1-4, Sumas and Mint Farm facilities;

(ii) adjustments proposed by Commission Staff and ICNU to reduce other production O&M costs;

(iii) an adjustment proposed by Commission Staff to reduce non-contracted major maintenance costs;

(iv) an adjustment proposed by Commission Staff to reduce other production O&M costs for Jackson Prairie rent expense; and

(v) an adjustment proposed by Commission Staff to reduce major maintenance amortization expense.

Finally, this prefiled rebuttal testimony describes and presents an update of PSE's projected rate year power costs, based on more recent known and measurable information.

II. PSE'S POWER COST ADJUSTMENT MECHANISM

Q. Please discuss the recommendations of Commission Staff and ICNU to remove power costs when setting base rates yet "recover" them through the PCA mechanism.

A. Both Commission Staff and ICNU suggest that the Commission should remove certain projected power costs from general rates and rely upon PSE's PCA mechanism to recover such costs.[1]

Q. What is the effect of these proposals?

A. These proposals effectively deny PSE recovery of all of these power costs. By removing these power costs from the baseline rate, PSE would have to exceed the $20 million deadband to recover *any* of these power costs. Even if PSE were to exceed the deadband, PSE would recover only a portion of its costs due to the sharing bands. Any suggestion that PSE would fully recover these power costs through the PCA mechanism is wrong.

Q. Which costs are Commission Staff and ICNU recommending be removed from base rates yet be included in the PCA mechanism's actual costs?

A. Commission Staff and ICNU propose that the Commission remove a total of $8.3 million and $6.9 million, respectively, of power costs from the baseline rate

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[1] *See, e.g.,* Exhibit No. ___CT(APB-1CT) at page 14, lines 19-22; *id*. at page 18, lines 16-19; Exhibit No. ___(DWS-1CT) at page 9, lines 16-21.

and allow these costs to flow through the PCA mechanism as shown in Table 1 below.

Table 1. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
Adjustments Proposed by Commission Staff and ICNU to Remove Costs from the Baseline Rate and Include in the PCA
($ in Millions)

Power Cost Adjustments	Commission Staff	ICNU
Day Ahead Wind Integration Costs *	($2.5)	($2.5)
Within Hour Wind Integration Costs	($2.9)	
Gas Hedges Mark To Market	($1.3)	($4.4)
Cedar Hills Mark To Market	($1.6)	
Total	($8.3)	($6.9)

* Per INCU's response to PSE's Data Request No. 30, Day Ahead Wind Integration costs are "appropriately handled through the PCA true-up mechanism".

PSE does not recover these costs merely because the actual costs would flow through the PCA. In fact, up to $11.4 million[2] of expected power costs would simply be denied recovery in rates. Under normal conditions, PSE would have to bear the cost of the $11.4 million disallowance plus another $8.6 million (11.4 + 8.6 = 20 million deadband) before customers would even begin sharing under-recovered costs under the PCA mechanism.

[2] Using Commission Staff's proposed adjustments and replacing the mark-to-market ("MTM") adjustment with ICNU's $4.4 million.

Q. Please explain PSE's PCA mechanism and the determination of the baseline rate.

A. PSE's PCA mechanism was developed as a way to insulate PSE and customers from volatilities inherent in PSE's electric portfolio. To work fairly and effectively, a baseline rate must represent the most accurate depiction of costs expected to be incurred during the rate year. As recognized by this Commission, a central purpose of the PCA mechanism is to protect PSE and its customers from extreme variations in power costs:

> A central purpose of the PCA the Commission approved for PSE, and similar mechanisms approved or considered for other companies, is to protect the companies against extreme variations in power costs caused by such factors as the extraordinary market events that occurred during 2001 and 2002, serious drought, or other circumstances that are beyond the companies' ability to foresee and control.

WUTC v. Puget Sound Energy, Inc., Order No. 08 at paragraph 20, Dockets UE-060266 & UG-060267 (Jan. 5, 2007).

Under the PCA mechanism, PSE bears 100 percent of the burden for the first $20 million of cost under-recoveries and receives the benefit for the first $20 million of cost over-recoveries. For the reasons discussed, it is imperative that the baseline rate be set as near as possible to projected rate year power costs because:

> PSE must bear the cash flow consequences during periods of under recovery. If the power cost baseline is set too low relative to actual prices, the greater the burden of those consequences for

> PSE's shareholders. Similarly, if the power cost baseline is set too high, ratepayers are burdened by the fact that they are paying more for power than what they should be paying. The PCA mechanism was meant to be fair to both shareholders and ratepayers.
>
> In summary, as we examine the power cost baseline from time to time—recognizing that it is important that we undertake that examination on a regular basis—we must strive to determine, with the greatest degree of precision that forward looking models can produce, an accurate estimate of actual costs that PSE will experience in the near and intermediate terms. It is a challenging task to estimate what the Company's actual costs of power will be in future periods, yet that is what we must strive to do so that the PCA mechanism functions, as intended, to balance the risk of excursions in power costs as equally as possible between ratepayers and shareholders.
>
> We resolve the philosophical question raised by ICNU in favor of the practical conclusion that *power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred* during short and intermediate periods following the conclusion of such proceedings.

WUTC v. Puget Sound Energy, Inc., Dockets Nos. UE-040640, *et al.*, Order 06 at paragraphs 106-108 (Feb. 18, 2005) (emphasis added).

Q. How has PSE's baseline rate costs projections of the AURORA model and the Not In Models compared to PSE's actual power costs over time?

A. Over the first ten PCA periods, beginning July 1, 2001 and ending December 31, 2011 PSE's actual power costs have tracked very closely to the respective allowed power costs. In fact, as shown in Table 2 below, power cost under-recoveries have been $27.9 million (or 0.25 percent of the actual allowed power costs).

Table 2. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
PCA Mechanism Actual (Over)/Under Recoveries
PCA Periods 1-10
($ in Millions)

Period	PCA Period	Actual Allowed Costs	Actual Recoveries	(Over)/ Under Recovery	Company Share	Customer Share
7/02-6/03	1	$845.0	$843.1	$1.8	$1.8	$0.0
7/03-6/04	2	$902.3	$872.8	$29.6	$24.8	$4.8
7/04-6/05	3	$959.4	$949.4	$10.0	$10.0	$0.0
7/05-6/06	4	$1,062.8	$1,075.2	($12.4)	($12.4)	$0.0
7/06-12/06	5	$596.4	$597.1	($0.7)	($0.7)	$0.0
1/07-12/07	6	$1,222.9	$1,253.1	($30.2)	($25.1)	($5.1)
1/08-12/08	7	$1,328.1	$1,329.9	($1.8)	($1.8)	$0.0
1/09-12/09	8	$1,404.9	$1,374.6	$30.3	$25.1	$5.1
1/10-12/10	9	$1,373.0	$1,336.9	$36.2	$28.1	$8.1
1/11-12/11	10	$1,351.7	$1,386.5	($34.8)	($27.4)	($7.4)
Cumulative (Over)/Under Recovery		$11,046.5	$11,018.6	$27.9	$22.4	$5.5
% Under Recovery through PCA 10				0.25%		

As expected, some years have resulted in under-recoveries and some years have resulted in over-recoveries. Over the cumulative history of the PCA mechanism, however, PSE's actual power costs have been close to the respective baseline rates. The types of costs Commission Staff and ICNU propose to exclude from rates have been included in the baseline rate since the inception of the PCA in the case of the MTM adjustments, and since PSE acquired wind resources in 2005, in the case of wind integration costs.

Q. Does PSE agree with Commission Staff's and ICNU's respective proposals to recover certain power costs only in the PCA mechanism?

A. No. PSE disagrees with Commission Staff's and ICNU's respective proposals to recover certain power costs only in the PCA mechanism. As discussed above, the

Commission should set the baseline rate as closely as possible to power costs that are reasonably expected to be actually incurred. The existence of a PCA mechanism should be irrelevant when setting base rates. If a PCA mechanism is in place and if the PCA mechanism indeed shifts risk from one stakeholder to another, it is the underlying conditions of the PCA mechanism itself (i.e., sharing bands and procedures) that should be adjusted to more appropriately balance risk between stakeholders—not the underlying power costs. The proposal of both ICNU and Commission Staff merely biases projected rate year power costs downward and should be rejected.

Q. Has PSE addressed the PCA mechanism in any of its filings with the Commission?

A. Yes, PSE has addressed the PCA mechanism in many filings with the Commission:

- In Docket UE-060266 (“2006 GRC”), PSE proposed to remove the deadbands in the PCA mechanism and to provide equal sharing of costs between PSE and its customers.

- In Docket UE-072300, PSE responded to proposed modifications and requests to eliminate the power cost only rate case ("PCORC") provisions of the PCA mechanism. PSE also proposed modifications to the PCORC provisions of the PCA mechanism. Finally, as ordered by the Commission, PSE undertook a study of the efficacy of the PCA sharing bands and identified three alternative methods to address the asymmetry of the power cost imbalance mechanism.

- In this proceeding, PSE provided updated analysis of the PCA mechanism in the Prefiled Direct Testimony of Mr. Salman Aladin, Exhibit No. ___(SA-1CT) and proposed no changes to the PCA mechanism.

Q. What is PSE's response to Commission Staff witness Schooley's request for a separate proceeding to review PSE's PCA mechanism, which includes PSE's ability to file a PCORC?

A. PSE questions whether another separate proceeding is necessary for such review. PSE presented analysis of the symmetry of the PCA sharing bands in its 2006 GRC. In addition, PSE has complied with the Commission's order in the past two cases and has provided analyses of the symmetry of the PCA sharing bands, but no party has responded to the study or the testimony PSE has provided.

II. REBUTTAL OF POWER COST ADJUSTMENTS

A. Summary of Proposed Adjustments to Power Costs and Production O&M

Q. Please provide a summary of the power cost and production O&M adjustments you will be discussing.

A. Table 3 below summarizes the proposed power cost adjustments of ICNU, Commission Staff and Public Counsel. Table 3 also summarizes PSE's proposed power cost adjustments and the PSE witness that discusses each adjustment.

Table 3. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
Power Cost Proposed Adjustments

No.	PSE Witness	Adjustment	ICNU	Commission Staff	Public Counsel	PSE
1	Mills	Day Ahead Wind Integration *	($2,516,579)	($2,516,579)	-	-
2	Mills	Within Hour Wind Integration *	-	(2,869,431)	-	-
3	Mills	Gas MTM *	(4,361,662)	(1,264,728)	-	-
4	Riding	Cedar Hills MTM *	-	(1,616,799)	-	-
5	Riding	Pipeline Escalation	(1,561,972)	-	-	(978,454)
6	Mills	Peaking	(1,055,900)	-	-	(481,604)
7	Story	FERC 557	(852,156)	-	-	-
8	Mills	Min Up	(400,000)	-	-	-
9	Mills	Transmission Reassignment Revenues	(1,132,832)	-	-	(1,217,957)
10	Mills	23MW Transmission Extension	-	(414,000)	-	-
11	Mills	Chelan - CRC/DRC	(2,638,585)	-	-	-
12	Mills	Chelan - Transmission	(141,103)	-	-	-
13	Story	Chelan $89M Reservation Prepay	-	-	(923,323)	-
14	Story	Colstrip 1/2 Amortization	-	(55,556)	-	-
15	Mills	LSR Credit - Buckley	-	(843,700)	-	(2,167,729)
16	Mills	LSR Credit - Martin	-	(2,047,435)	-	-
17	Mills	Use of AURORA Single Run vs 70-Year	(1,106,583)	-	-	-
18	Mills	Gas Price Update	(26,700,000)	(9,960,000)	-	(11,976,882)
19	Mills	MidC Update	-	-	-	359,079
20	Mills	Colstrip Updates	-	-	-	(1,564,135)
		Total Proposed Adjustments	($42,467,371)	($21,588,228)	($923,323)	($18,027,682)

* Commission Staff and ICNU propose to remove costs from baseline rates and allow them to flow through the PCA mechanism.

Table 4 below summarizes the proposed production O&M adjustments of ICNU, Commission Staff and Public Counsel. Table 4 also summarizes PSE's proposed production O&M adjustments and the PSE witness that discusses each adjustment.

Table 4. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
Production O&M Proposed Adjustments

No.	PSE Witness	Adjustment	ICNU	Commission Staff	Public Counsel	PSE
1	Gould	Maintenance = 4-year Avg	(7,101,716)	-	-	-
2	Gould	Other Production O&M = 2012 Budget	(1,265,488)	(689,624)	-	-
3	Gould	Non-Contract Major Maint = 5-year Avg	-	(3,540,000)	-	-
4	Gould	Major Maintenance Amortization	-	(1,062,520)	-	-
5	Mills/Riding	Jackson Prairie Rent = Current Contract	-	(303,825)	-	(303,825)
6	Mills	Colstrip Budget Update				(2,626,645)
		Total	($8,367,204)	($5,595,969)	$0	($2,930,470)

B. Day-Ahead Wind Integration Costs

Q. Please describe the power cost adjustment proposed by Commission Staff and ICNU with respect to PSE's day-ahead wind integration costs.

A. Both Commission Staff and ICNU have proposed the removal of all of PSE's costs of integrating its wind resources on a day-ahead basis. *See* Exhibit No. ___(APB-1CT) at page 16, line 16, through page 21, line 12; Exhibit No. ___(MCD-1CT) at page 6, line 17, through page 8, line 7. This proposed adjustment would reduce power costs by approximately $2.5 million.

Q. Please explain what day-ahead wind integration costs represent.

A. The day-ahead wind integration costs are costs PSE incurs due to the variability and uncertainty of wind power generation. These costs represent the "opportunity" costs associated with setting up a power portfolio position on the day-ahead basis (employing a forecast of wind generation) as contrasted to the hour-ahead generation level that actually occurs.

Q. Can PSE model costs to integrate wind resources on a day-ahead basis?

A. Yes. There are two components to modeling the day-ahead wind integration cost: (a) the day-ahead wind production forecast error, which represents the energy component; and (b) the market price differential between day-ahead and hour-ahead, which represents the per-MW "opportunity" cost component.

For the energy component, PSE maintains historical records of day-ahead wind production forecasts and real-time wind production schedules for all of PSE's owned wind facilities. This difference depicts, on an hourly level, whether the wind production position is long or short relative to the day-ahead forecast, and by what amount. For the market price component, PSE compares the day-ahead peak and off-peak energy prices to the real-time spot energy price, using the Dow Jones Mid-Columbia ("Mid-C") Index. This difference depicts, on an hourly level, the cost of the forecast error.

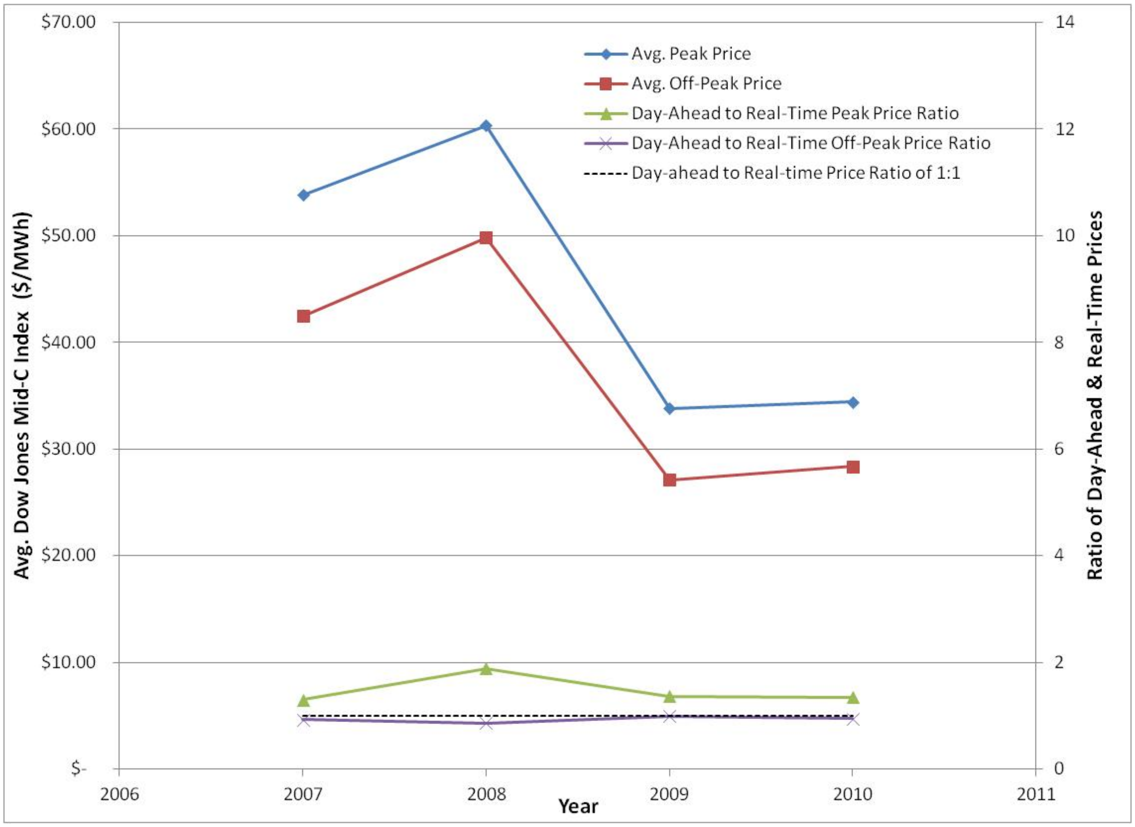
Together, these two components represent the opportunity cost of integrating PSE's wind assets day-ahead. For example, consider two consecutive hours from April 2010. In the first hour, the day-ahead forecast for Hopkins Ridge was 86 MW, and the day-ahead firm peak price was $31.39/MW. In real-time, the wind forecast updated to 90 MW and the real-time market price was $20.12/MW. The wind forecast error resulted in a 4 MW surplus, which is priced at an "opportunity" cost of $11.27/MW, representing the lost marginal revenue from being unable to sell the surplus 4 MW in the day-ahead market, resulting in a total day-ahead wind integration cost of $45.08 (4 * 11.27) for that hour.

In the subsequent hour, the day-ahead forecast was 93 MW, which was then updated to 70 MW in real-time. The day-ahead peak price was still $31.39/MW for the hour, with a real-time price of $18.36/MW. In this hour, the day-ahead forecast error resulted in a deficit of 23 MW in real-time, which in this case ends up being a benefit because the real-time market price is lower than the day-ahead price and results in a marginal benefit of $13.03/MW. The day-ahead wind integration cost is actually a benefit in this hour, of $299.69 (23 * 13.03).

Q. How did PSE use the historical price data to model the day-ahead wind integration costs for the rate year?

A. When estimating the day-ahead wind integration costs for the rate year, PSE applied the historical relationship between the day-ahead and real-time prices to the forecasted market prices from AURORA. PSE uses this relationship to de-trend movements in market prices. Although power prices can vary year-to-year, the relationship between day-ahead prices and real-time prices is relatively constant. Table 5 below, which graphs the 2007-2010 average Dow Jones Mid-C Index prices and the ratio of day-ahead to real-time prices, provides a graphical depiction of this relationship.

Table 5. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
Relationship between Day-Ahead Prices and Real-Time Prices



As shown in Table 5 above, the ratio of the day-ahead to real-time price stays consistent over the same timeframe. PSE then applies the historical ratios to the AURORA forward market prices to create day-ahead on- and off-peak prices to reflect the expected differences in the day-ahead and real-time prices for the May 2012 to April 2013 rate year.

Q. Can PSE track actual costs to integrate its wind resources on a day-ahead basis?

A. PSE maintains a dynamic power portfolio comprised of load and generating assets. Therefore, it is difficult to isolate and track the effects of just one variable (i.e., wind forecast error). Although balancing actions may not be directly attributed to correcting the day-ahead forecast error, the magnitude and opportunity cost of the day-ahead wind production forecast error on PSE's market position is known and capable of measurement. PSE models these by using the changes in the Dow Jones Mid-C day-ahead prices to the Dow Jones Mid-C real-time prices.

Q. Is ICNU correct when it asserts that day-ahead wind integration costs are included in the AURORA model?

A. No. ICNU is incorrect in asserting that AURORA fully accounts for day-ahead wind integration costs because AURORA calculates "the expected value of the variable costs of operating PSE's generating resources." Exhibit No. ___(MCD-1CT) at page 7, lines 19-21. As explained above, the calculation of wind integration costs involves a comparison of wind forecasts to actual wind generation, but the PSE wind profiles in AURORA only use a set of fixed generation profiles for each plant. These fixed profiles do not account for any day-ahead forecast error.

The AURORA model dispatches PSE's combustion turbines based upon their individual operating information as compared to the market heat rates in AURORA. Therefore, the fixed hourly generation of PSE's wind resources have no impact on AURORA modeled gas fired units' generation or costs. By having essentially zero operating costs, wind generation is more akin to a reduction in load rather than a reduction in PSE's generating assets.

Moreover, the designation of wind resources as "must run" in AURORA does not capture the day-ahead uncertainty in wind production. AURORA models wind production as fixed and firm and does not consider how changes in the wind production forecast from day-ahead to real-time affects power costs. The fact that costs associated with wind variability and uncertainty are not included in the AURORA model is precisely why these costs have been modeled separately using actual data and included in the Not in Models costs.

Q. Do other entities recognize that there are day-ahead wind integration costs?

A. Yes. It is understood in the industry that consideration of day-ahead forecasts into the day-ahead (unit commitment) generation planning process are (i) essential to efficient system operations and (ii) real and measurable.[3]

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[3] *See, e.g., Western Wind and Solar Integration Study* (May 2010), prepared by GE Energy on behalf of the National Renewable Energy Laboratory, *available at* http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf; North American Electric Reliability Corporation, NERC IVGTF Task 2.4 Report; Operating Practices, Procedures, and Tools (Mar. 2011), available at http://www.nerc.com/files/IVGTF2-4.pdf.

Q. Do you know of other Northwest utilities that recover or have calculated day-ahead wind integration costs?

A. Yes. Portland General Electric Company filed a general rate case before the Public Utility Commission of Oregon (Docket # UE 215), which included a day-ahead wind integration cost of $0.50 per MWh. The Idaho Public Utility Commission ("Idaho PUC") has approved total wind integration rates, including day-ahead costs, of $6.50 per MWh for PacifiCorp (Case No. PAC-E-09-07, Order No. 31021). In that PacifiCorp case, the Idaho PUC ruled that it "continues to find that the cost of wind integration for utilities is real and greater than zero" (*Id*. pg. 8). PacifiCorp has proposed day-ahead wind integration costs of $0.70 per MWh for 2012 and $1.21 per MWh for 2013 in its rate case before this Commission (Docket UE-111190). These compare to PSE's day-ahead wind integration costs which range between [redacted] and [redacted] per MWh, depending on the wind facility.

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Q. Does PSE agree that it is "inappropriate" and "arbitrary" to include day-ahead wind integration costs in the rate year?

A. No. As addressed above, the presumption that AURORA fully accounts for day-ahead wind integration costs is inaccurate. AURORA does not capture the day-ahead uncertainty of wind production and the associated costs that are managed in actual real-time power operations. In addition, at this time, the costs associated with integrating PSE's wind resources on a day-ahead basis cannot be modeled in

AURORA. Therefore, the decision to model day-ahead wind integration costs outside of AURORA is necessary and not "arbitrary".

Q. Why did PSE develop projected day-ahead wind integration costs for Lower Snake River Phase 1 Wind Project ("LSR Phase 1") using characteristics of the Hopkins Ridge Wind Project ("Hopkins Ridge")?

A. LSR Phase 1 is not yet operational, but PSE has an expected in-service date of mid-February 2012. PSE relied on the characteristics of Hopkins Ridge as a reasonable proxy for LSR Phase 1. Hopkins Ridge and LSR Phase 1 are separated by less than one mile at the north edge of Hopkins Ridge and reside in the same windshed. Therefore, it is reasonable that day-ahead forecast errors at Hopkins Ridge will similarly affect LSR Phase 1.

Q. Is it correct to suggest that there is no evidence that PSE loses any "day-ahead" opportunity?

A. No. PSE considers the day-ahead wind forecasts for Hopkins Ridge, Wild Horse and the Klondike III Wind Project ("Klondike III") as firm generation when planning the generation stack and market positions required to meet load for the following day. To ensure sufficient balancing capacity in real-time, PSE must transact in the day-ahead market or commit thermal units based on day-ahead market prices or heat rates. When real-time market prices clear, PSE's day-ahead operating practice results in *both* incremental costs and benefits. The Commission should reject Commission Staff's and ICNU's respective recommendations to ignore these costs and benefits by adopting PSE's proposed adjustment, which accounts for the pro forma net cost implications of day-ahead wind generation forecast uncertainty.

C. Wild Horse Wind Integration Costs

Q. Please describe the power cost adjustment proposed by Commission Staff with respect to PSE's within-hour wind integration costs.

A. Commission Staff proposes that the Commission ignore PSE's within-hour wind integration costs on the flawed premises that such costs lack "sufficient robustness for inclusion in rate year net power costs" and "do not rise to a sufficient level of certainty to warrant inclusion". *See* Exhibit No. ___(APB-1CT) at page 20, lines 3-7.

Q. What are within-hour wind integration costs?

A. Within-hour wind integration costs reflect costs incurred as actual wind generation levels vary within each operating hour after delivery schedules are established and tagged. In instances where wind generation changes within the hour, other PSE resources must be adjusted to counter the movements in wind production in order to maintain the system's load-resource balance. Additionally, PSE's resources must stand ready at the start of each hour to balance any fluctuations in wind generation, regardless of whether they occur or not.

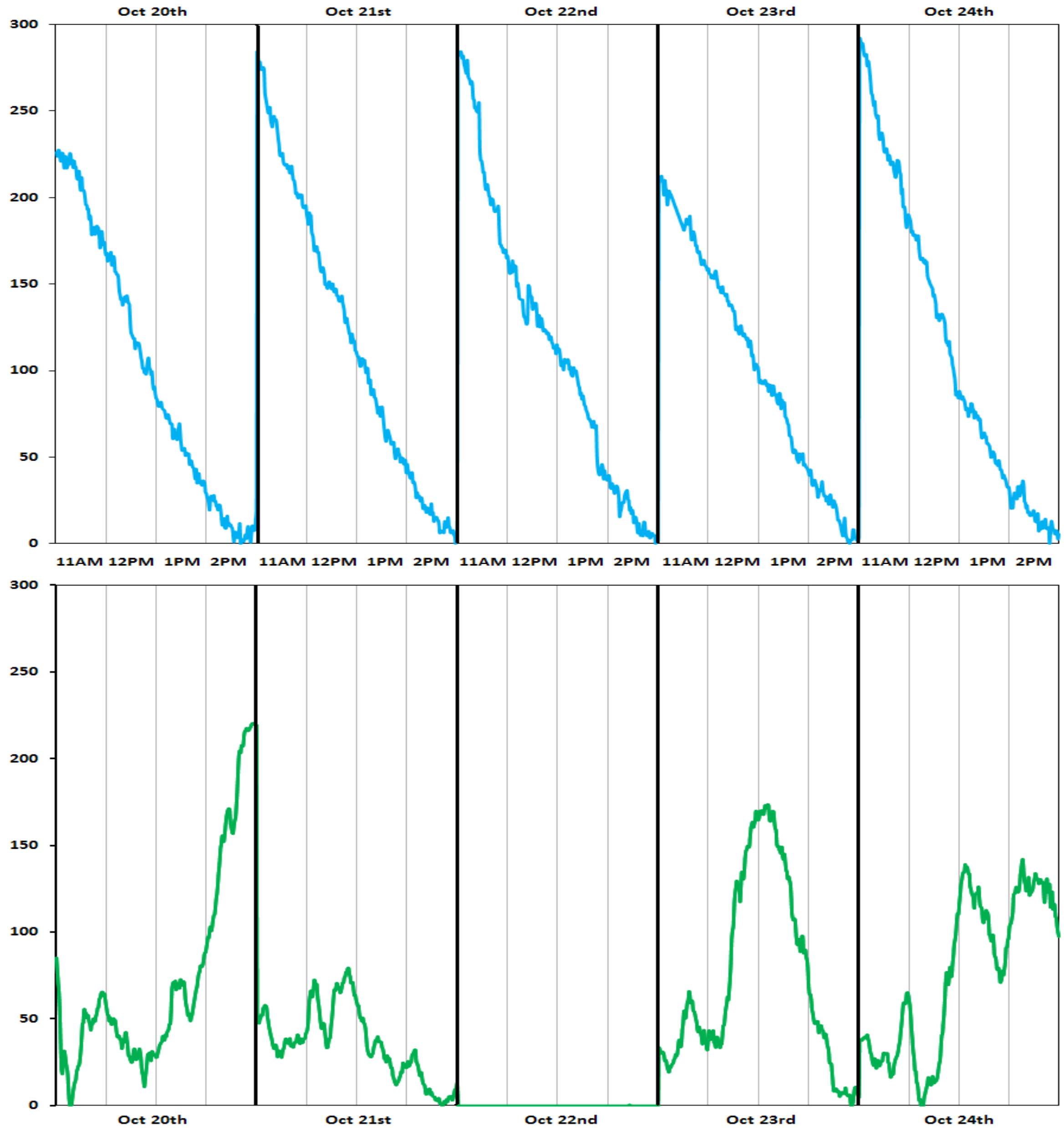
Q. Please describe the difficulties in balancing within-hour deviations due to wind fluctuations.

A. As the balancing authority for Wild Horse, PSE is obligated to balance any hourly fluctuations in wind output in order to maintain system reliability. While these fluctuations may be similar to those observed with load, wind generation poses its own unique challenges.

For example, Table 6 depicts the same four hour period, from 11:00AM to 3:00PM, for the five weekdays of October 20th – October 24th, 2008. The top portion shows a snapshot of the PSE system load during this series of four-hour windows. Across these five days, the magnitude and direction of daily load movements are near identical. PSE has great ability to anticipate system load, especially the shape of load, and therefore can position its system resources to follow changes in load within the hour and into the next hour with high certainty.

The lower portion shows Wild Horse generation movement during the same week and four-hour window. While these traces show the volatility of wind generation within the hour and between hours that PSE must manage, it is also important to note these traces do not convey the uncertainty in the forecast, an important difference between movements in load and wind. Even if PSE has expectations of a near-term wind ramp, PSE cannot be certain of the wind ramp's ultimate magnitude, duration, and timing and must stand ready with available system resources every hour to meet this uncertainty.

Table 6. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
Load Versus Wild Horse Wind Uncertainty



Q. For which resources does PSE incur within-hour wind integration costs?

A. PSE incurs within-hour wind integration costs for all of its wind resources. Specifically, Hopkins Ridge, Klondike III, and LSR Phase 1 are, or will be, within the Bonneville Power Administration ("BPA") Balancing Authority; therefore, PSE is expected to pay the BPA Variable Energy Resource Balancing Service ("VERBS") tariff rate of $1.23 per kilowatt-month ("kW-mo.") to balance generation from these wind resources. Wild Horse is within PSE's Balancing Authority; therefore, PSE bears the direct costs of integrating wind generation from Wild Horse. PSE has modeled the within-hour wind integration costs of Wild Horse to be $[redacted] per MWh (or $[redacted] per kW-mo.) as compared to BPA's VERBS rate of $1.23/kW-mo. (which translates to $[redacted]/MWh using Wild Horse wind generation). Please see Exhibit No. ___(DEM-1CT) at page 25, line 1, through page 30, line 15, for a discussion of PSE's within-hour wind integration costs. If PSE were to move Wild Horse into the BPA Balancing Authority, this rate differential would result in an increase in power costs of approximately [redacted].

REDACTED VERSION

Q. Does PSE's wind integration modeling lack "sufficient robustness"?

A. No. In developing the within-hour balancing reserve requirements for Wild Horse, PSE's SAS-based Ancillary Valuation Model ("AVM") relies on four years (2007 through 2010) of data at 10-minute intervals to provide PSE with an accurate estimate of the wind generation variability it must manage within each operating hour. Use of hourly AURORA dispatch allows AVM-calculated within-hour wind integration costs to be tied to the rate year forecasts for resource dispatch, power and gas prices, and hydro conditions. The AVM logic for altering AURORA's gas fired units and hydro dispatch information follows a structured process, adjusting the dispatch only when warranted by insufficient balancing reserve capacity. If the AVM determines there is insufficient balancing reserve capacity, the AVM modifies the AURORA dispatch information in a least-cost manner using PSE's Mid-C hydro resources first and then thermal resources only when necessary, taking into consideration thermal units heat rates and operational availability.

Each step in the AVM relies on known and measurable data, whether the historical within-hour wind volatility or the unique operating characteristics of each resource, and is consistent with the AURORA simulation of hydro and price conditions for the rate year. In the final step, the AVM calculates the within-hour Wild Horse wind integration cost by summing all hourly production costs and benefits resulting from its AURORA dispatch adjustments over the year. The total dollar amount is divided by the total annual forecast MWh output from Wild Horse to arrive at a dollar per MWh within-hour wind integration cost. Incorporating all 70 AURORA model simulations allows PSE to create a distribution of within-hour wind integration costs, which in turn allows PSE to be more certain in the expected cost, which is the proposed rate of $[redacted]/MWh (or $[redacted] per kW-mo.).

REDACTED VERSION

Q. Should PSE be able to recover its within-hour wind integration costs in its baseline rate?

A. Yes. The Commission should allow PSE to recover the within-hour wind integration costs for Wild Horse in the same manner that it recovers within-hour wind integration costs paid to BPA through the VERBS rate. Variations in wind generation within the hour impose real costs on the PSE system, and the Commission should allow PSE to recover these costs.

D. Gas For Power Hedges

Q. Please describe the adjustment ICNU and Commission Staff propose regarding the mark-to-market for natural gas for power hedges.

A. ICNU and Commission Staff each propose to impose a cap on the monthly volume of the rate year gas for power hedges. ICNU proposes to remove the *monthly* volume of gas hedges—priced at the *monthly* average cost for all natural gas hedges—that exceed the *monthly* gas need as calculated using the AURORA model gas fired generation. ICNU calculates that this adjustment would reduce projected rate year power costs by approximately $4.4 million. *See* Exhibit No. ___(DWS-1CT) at page 8, line 11, through page 10, line 12.

Commission Staff proposes to remove the *annual* volume of gas hedges—priced at the *annual* average cost for all natural gas hedges—that exceed the *annual* gas need calculated using the AURORA model gas fired generation. Commission

Staff calculates that this adjustment would reduce projected rate year power costs by approximately $1.3 million. *See* Exhibit No. ___(ABP-1CT) at page 15, line 20, through page 16 line 1.

Q. Has ICNU or Commission Staff proposed adjustments to PSE's gas for power hedging transactions in past rate proceedings?

A. Yes. In PSE's last general rate case, ICNU presented proposals to limit PSE's cost recovery of gas for power hedges to a volume of gas based upon the AURORA model generation and based such proposals on similar arguments as provided in this proceeding.

Q. Did the Commission accept the proposals in PSE's last general rate proceeding to limit cost recovery of gas for power hedges to a volume of gas based upon the AURORA model generation?

A. No. The Commission expressly rejected the proposals in PSE's last general rate proceeding to limit cost recovery of gas for power hedges:

> The mark-to-market adjustment for gas contracts and hedges has been a relatively uncontroversial example of such an adjustment for many years. In this case we are presented with an adjustment that encompasses the same category of costs that have been regularly included in approved baseline power costs rate, but that is much larger than in the past. We find that the parties proposing to change the way mark-to-market gas hedges are treated in determining power costs have failed to present any convincing reason to do so.
>
> [PSE] is correct to argue the importance of matching all costs, benefits, and other factors when rates are adjusted. And it is disappointing to hear ICNU/Staff and Public Counsel advocate a single issue rate adjustment

> when they otherwise so vigorously and correctly defend the matching principle. If hedging is an appropriate tactic to manage fuel cost risk, and we think it is, then it is appropriate for the cost of hedges to be included in power cost rates.
>
> While it is true that the intrinsic value of hedges will vary with the actual cost of gas, this does not make hedging costs any less known and measurable than the market cost of gas that is an input to the AURORA model. We don't find ICNU's argument for excluding a mark-to-market adjustment on this basis consistent or persuasive.
>
> This adjustment has routinely been an element of the power cost calculation and we can see no principled reason to exclude it from rates simply because of its size in this case….

WUTC v. Puget Sound Energy, Inc., Dockets UE-090704 & UG-090705, Order 11 at paragraphs 151-55 (Apr. 2, 2010).

Q. Is ICNU's application of their removal of PSE's gas for power hedges from the baseline rate accurately calculated?

A. No. ICNU inaccurately calculates the removal of certain gas for power hedge costs from the baseline rate.

For example, ICNU uses the volumes of both physical and financial gas hedged at Sumas to determine the quantity above the AURORA need. By including both the physical and financial hedges, ICNU is, in effect, double counting the volumes hedged because it is common to hedge both financially (as to price) and physically (as to ensure delivery of the physical natural gas commodity). Correcting such double-counting would reduce ICNU's calculated power cost reduction by approximately $0.5 million.

Additionally, ICNU erroneously uses the average cost of all hedges for a month rather than the average cost of the hedges to be removed to determine the reduction to power costs. If ICNU had appropriately included the average cost of the hedges *retained* in projected power costs for the rate year and removed the average cost of the hedges *removed* in projecting power costs for the rate year, then ICNU's calculation of reduced power costs would be approximately $3.6 million lower.

Correcting for the above-described errors, ICNU's proposal to remove certain gas for power hedges from the baseline rate would decrease projected power costs by approximately $0.3 million.

Q. Does Commission Staff calculate the removal of PSE's gas for power hedges from the baseline rate accurately?

A. No. Commission Staff commits similar errors to those committed by ICNU in calculating the removal of certain gas for power hedges from the rate year power costs. Similar to ICNU, Commission Staff erroneously uses the average cost of *all* hedges for the rate year rather than the average cost of the hedges *removed* to determine the reduction to power costs. Correcting for this error alone, Commission Staff's proposal to remove certain gas for power hedges from rate year power costs would decrease projected power costs by approximately $0.2 million.

Moreover, Commission Staff suggests that the Commission could include the gas volumes for the Cedar Hills Regional Landfill facility ("Cedar Hills") in the determination of the mark-to-market costs to remove from projected power costs for the rate year. If the Commission were to adopt this proposal and correct the error described above, then the Commission Staff proposal to remove certain gas for power hedges from the baseline rate would *increase* projected power costs by approximately $1.9 million.

Q. Commission Staff claims "the true costs of any fixed price gas hedges entered into by the Company are not known until the rate period passes". Is this correct?

A. No. The mark-to-market amount for a fixed gas for power contract – or any fixed-price contract –changes only due to changes in market prices. The price of the contract stays the same. Commission Staff has their logic reversed – it is the forward, unhedged gas prices that can vary significantly throughout a rate proceeding. Procuring energy or natural gas using a fixed price commodity instrument is the premise and objective of PSE's hedging program. Since the price of a fixed gas-for-power hedge (or any fixed priced contract) does not change during the course of a rate case, neither does its cost change. In essence, the mark-to-market adjustment is maintaining the fixed price of the gas contract relative to the variable gas market prices which are an input to AURORA. The fixed price of a contract is known as soon as it is transacted and it does not change. Fixed price contracts are known and measurable.

Q. Are the mark-to-market adjustments for natural gas hedges recommended by ICNU or Commission Staff reasonable?

A. No. The mark-to-market adjustments for natural gas hedges recommended by ICNU and Commission Staff are unreasonable because PSE does not use the AURORA model generation need for hedging purposes. For day-to-day active management of the power portfolio, PSE uses a probabilistic modeling risk system that runs several times weekly, using updated operational and market intelligence that includes regularly updated prices of power, natural gas, and resulting market heat rates.

Although Commission Staff and ICNU do not challenge PSE's hedging program, they suggest that the resulting costs associated with these measures do not warrant full recovery in base rates. PSE has not significantly modified its energy commodity hedging strategies since its last general rate proceeding. In addition, this strategy and the resulting hedges have been explained in detail in PSE's prior nine PCA compliance filings.

Therefore, the Commission should reject—as it did in the last general rate proceeding—the proposals of ICNU and Commission Staff with respect to the mark-to-market adjustment for gas contracts. Neither ICNU nor Commission Staff have presented convincing reasons to change the treatment of mark-to-market hedges for ratemaking purposes.

E. Cedar Hills Gas Cost

Q. Please describe Commission Staff's proposed adjustment for Cedar Hills.

A. Commission Staff proposes to reduce rate year power costs by approximately $1.6 million to remove the mark-to-market costs under PSE's contract with Bio Energy Washington for natural gas purchased from Cedar Hills. These costs represent the difference between the contracted price arrangement and the rate year forward market prices. Commission Staff also proposes that the actual costs of the Cedar Hills gas be included with the actual power costs within the PCA mechanism. I have explained earlier why this type of "solution" for recovery of actual power costs in the PCA mechanism is not appropriate.

Q. Did PSE purchase gas from Cedar Hills to meet generation needs?

A. Yes. PSE purchased gas from Cedar Hills to meet generation needs. PSE has determined that, at this time, it is more advantageous to PSE and its customers to sell the environmental attributes associated with such gas than to use such gas to generate power. As stated in direct testimony, PSE will defer revenues from the sale of the Cedar Hills environmental attributes for future customer credit according to the accounting determined for Renewable Energy Credits. Exhibit No. ___(DEM-1CT) at page 33, line 21, through page 34, line 1. Please also refer to discussion in the Prefiled Rebuttal Testimony of Mr. R. Clay Riding, Exhibit No. ___(RCR-4T).

Q. What is PSE's proposal regarding the mark-to-market adjustment for the Cedar Hills gas contract?

A. PSE requests the Commission reject Commission Staff's $1.6 million reduction to power costs and include the mark-to-market for the Cedar Hills gas in rate year power costs. If the Commission, however, were to adopt Commission Staff's adjustment, then PSE proposes the Commission also order that all the costs of the gas purchased from Cedar Hills be offset against the revenues associated with its environmental attributes. In this manner, PSE customers would then receive all benefits and pay all costs associated with such gas.

F. Gas Pipeline Costs

Q. Please describe the power cost adjustment proposed by ICNU with respect to gas pipeline costs.

A. ICNU proposes to remove rate year forecast cost increases for PSE's contracted pipeline obligations with Westcoast Energy, Inc., Northwest Pipeline GP and Cascade Natural Gas and reduce power costs $0.78 million, $0.69 million and $0.09 million, respectively, for a total cost reduction of $1.56 million. *See* Exhibit No. ___(MCD-1CT) at page 10, line 21, through page 11, line 27. As discussed in the Prefiled Rebuttal Testimony of Mr. R. Clay Riding, Exhibit No. ___(RCR-4T), the Commission should reject ICNU's proposal.

G. Winter Peak Planning

Q. What are the costs incurred by PSE to meet winter peak demand?

A. As a public service company, PSE must meet the energy demands of its customers across all hours. PSE obtains peaking resources to meet winter peak hour loads and to maintain all reliability criteria, such as operating reserves. Peaking resources include generating resources, purchased peak energy contracts to ensure the availability of physical power and transmission to ensure delivery of such power to PSE's system during peak hours. With the Mid-C hub as the primary source of regional power supply, PSE must consider its available transmission capacity from the Mid-C hub to PSE's system against the forecast power needs.

Q. Is PSE's use of a 15.7 percent planning margin appropriate in determining peak needs for the rate year?

A. Yes. PSE's use of a 15.7 percent planning margin is appropriate in determining peak needs for the rate year. PSE first introduced its revised planning standard in its 2009 Integrated Resource Plan, which PSE provided in Exhibit No. ___(RG-3). The use of planning margin is consistent with the regional standard formally adopted by the Northwest Power and Conservation Council ("NPCC") to assess the adequacy and reliability of resources within the next five years to meet different uncertainties in loads, hydro, forced outage rates and wind. The NPCC uses the Loss of Load Probability ("LOLP") methodology (as opposed to using historical actuals because historical actuals do not reflect all of the uncertain events that could happen) and has adopted a five percent LOLP standard as a reliability metric. This five percent LOLP standard implies that resources should be adequate to meet loads 95 percent of the time under all combinations of risk events with respect to temperature (loads), hydro, forced outage rates, and wind. PSE has adopted the same methodology and translated the five percent LOLP to a planning standard of 15.7 percent (i.e., the percent over normal peak load that allows PSE to meet the 5 percent LOLP standard) as described in the 2009 IRP.

Q. How did PSE formally adopt the higher planning standard?

A. Subsequent to filing its 2009 IRP, PSE made a concerted effort to ensure its operational reliability practices mirrored planning standards outlined in the 2009 IRP. PSE conducted further analytical studies of this planning standard and refined the planning margin. The current 15.7 percent planning margin was presented as a 2009 IRP Addendum. *See* Exhibit No. ___(RG-4). PSE currently uses the 15.7 percent planning margin in short-term planning to meet winter peak loads and in long-term planning as presented in PSE's 2011 Integrated Resource Plan.

Q. Please describe ICNU's proposed adjustment to PSE's winter peak planning costs.

A. ICNU proposes to remove costs to procure on-peak physical power to meet winter months' peak loads:

> While acknowledging that there can be constraints to the availability of Mid-C transmission capacity or due to insufficient resources to meet the peak load, *the crux of the issue is really the number of hours this is likely to occur*. PSE has assumed resource shortages will occur in each and every on-peak hour of the four-month period based on the assumed monthly peak times a planning reserve margin of 15.7%. This is simply not realistic.

Exhibit No. ___(DWS-1CT) at page 14, lines 3-9 (emphasis added).

Q. Please describe the peak load ICNU proposes be used for PSE's peak needs.

A. ICNU starts with actual hourly loads for only four years (2007-2010) to determine which four winter months of the four years will be used to apply a simplistic normalization factor upon every hour, and proceeds to determine a more "realistic" peak load forecast. ICNU's "analysis" determines that PSE should plan to meet peak customer demand by purchasing physical power for only specific hours of each month - 18 hours in January, 19 hours in February, 25 hours in November and 39 hours in December, for a total of 22,432 MWhs. In this regard, ICNU removes $1.1 million from rate year power costs. Exhibit No. ___(DWS-1CT) at page 14, line 13, through page 16, line 5.

Q. Is ICNU's proposed method appropriate?

A. No. ICNU's proposed methodology is inappropriate for a variety of reasons.

First, ICNU's methodology attempts to base peaking costs on "expected hours where loads actually exceed PSE's resource capacity". In reality, PSE must be prepared for *unexpected* winter peak events. PSE's procurement of its peak obligations well in advance of the winter peaking event is similar to the purchase of an insurance policy to avoid a catastrophic situation. If PSE were to plan to meet its needs in a manner similar to that proposed by ICNU, PSE would run the risk that it would be unable to purchase power in the market. If PSE were unable to purchase power in the market, it would have no choice but to shed load.

Secondly, ICNU's proposal to avoid planning for all peak hours presupposes the Company is able to predict the actual hour in which a peak event will occur. Since this is impossible, PSE assumes resource shortages will occur in each and every peak hour of the four winter months. This is the only way PSE can avoid the risk described and ensure system generation reliability.

Third, even if PSE had perfect foresight and knew the exact hours in which its load would exceed its available resources, no reliable standard hourly option product exists in the market. If PSE were to procure such a product in advance, the premium would undoubtedly be very high and could easily exceed the market price used by ICNU.

Q. Has PSE updated its winter peaking costs?

A. Yes. PSE has updated its winter peak costs to reflect AURORA modeled generation as updated with more recent gas prices and actual power transactions as of the December 8, 2011 gas price cutoff date. PSE proposes to reduce rate year winter peaking costs by $0.5 million and urges the Commission reject

ICNU's proposed methodology for determining peak resource shortfalls and its corresponding $1.1 million adjustment.

H. FERC 557 Other Power Costs

Q. Please explain ICNU's proposed adjustment to FERC Account 557, Other Power Costs.

A. ICNU asserts that the amounts in PSE's FERC 557 have experienced "significant variation through the years". *See* Exhibit No. ___(MCD-1CT) page 12, line 8. Thus, ICNU proposes to set the rate year costs at a level equal to the average of the most recent five years. ICNU's proposed adjustment reduced rate year power costs by approximately $0.9 million. *Id.* at page 12, line 1, through page 13, line 2.

Q. Do you agree with ICNU's argument and adjustment to FERC 557 costs?

A. No. As shown in the Prefiled Rebuttal Testimony of John H. Story, Exhibit No. ___(JHS-18T), PSE's FERC 557 costs have been increasing over the five years of data analyzed by ICNU in what appears to be a consistent trend. ICNU's argument to normalize such trended data to remove "significant variation" and "provide a more appropriate level of expense for prospective ratemaking purposes" is simply unfounded. PSE urges the Commission to reject both of ICNU's adjustments in FERC 557 costs which total $1.8 million (power cost adjustment of $0.9 million and administrative and general expense adjustment of $0.9 million).

I. AURORA Model Inputs

Q. Please describe ICNU's adjustment to the thermal operating assumptions in the AURORA model.

A. ICNU proposes to modify the AURORA model inputs for the minimum up times for PSE's Goldendale, Mint Farm and Sumas combined cycle combustion turbines. This adjustment would reduce power costs by approximately $0.4 million. Exhibit No. ___(MCD-1CT) at page 13, lines 3-23.

Q. What are the thermal operating assumptions in the AURORA model?

A. The AURORA model makes commitment and dispatch decisions on an hourly basis utilizing the resource characteristics of the thermal generators and the costs of fuel. These characteristics include items such as operating capacity, base load heat rates, minimum up times and minimum down times. The thermal operating assumptions represent PSE's operating information used to dispatch and operate PSE's combustion turbine fleet.

Q. Please describe ICNU's proposed changes to the AURORA model minimum up times.

A. Based upon actual hourly operating data, ICNU proposes to impose a 10-hour minimum up time for Goldendale, Mint Farm and Sumas rather than the AURORA model inputs of 24-hours for Goldendale and Mint Farm and 16-hours for Sumas. Exhibit No. ___(MCD-1CT) at page 13, lines 18-21.

Q. Do you agree with ICNU's proposed changes to the AURORA model minimum up times?

A. No. ICNU's proposal to adjust the AURORA model minimum up times reflects only a portion of the changes to the operating characteristics of the combustion turbines. PSE's asset management group, in concert with PSE plant managers, maintain and review actual plant operating statistics to ensure PSE's gas fired combustion turbines are operating efficiently and reliably given the operating and maintenance constraints of the individual turbines. Over the years, as the combustion turbines age and receive normal and major maintenance, the thermal operating characteristics of the combustion turbines will vary. PSE's thermal operations group provides updates to the thermal operating characteristics on an ongoing basis such that the operators are using the most current information to make plant dispatch decisions. At this time, several of the thermal operating characteristics associated with PSE's combustion turbines have been updated. In addition to the minimum up times noted by ICNU, PSE's thermal operations group has authorized changes to the combustion turbines' operating characteristics for capacity, minimum down times, and heat rates. If PSE were to update the AURORA model with all of the assumption changes, rate year power costs would *increase* approximately $2.6 million as shown in Table 7 below.

Table 7. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
Impact of AURORA Model Thermal Inputs
($ in Thousands)

Period	PCA Period	Actual Allowed Costs	Actual Recoveries	(Over)/ Under Recovery	Company Share	Customer Share
7/02-6/03	1	$845.0	$843.1	$1.8	$1.8	$0.0
7/03-6/04	2	$902.3	$872.8	$29.6	$24.8	$4.8
7/04-6/05	3	$959.4	$949.4	$10.0	$10.0	$0.0
7/05-6/06	4	$1,062.8	$1,075.2	($12.4)	($12.4)	$0.0
7/06-12/06	5	$596.4	$597.1	($0.7)	($0.7)	$0.0
1/07-12/07	6	$1,222.9	$1,253.1	($30.2)	($25.1)	($5.1)
1/08-12/08	7	$1,328.1	$1,329.9	($1.8)	($1.8)	$0.0
1/09-12/09	8	$1,404.9	$1,374.6	$30.3	$25.1	$5.1
1/10-12/10	9	$1,373.0	$1,336.9	$36.2	$28.1	$8.1
1/11-12/11	10	$1,351.7	$1,386.5	($34.8)	($27.4)	($7.4)
Cumulative (Over)/Under Recovery		$11,046.5	$11,018.6	$27.9	$22.4	$5.5
% Under Recovery through PCA 10				0.25%		

Q. Does PSE propose to update the AURORA model inputs for these most current thermal plant operating characteristics?

A. No. PSE is not proposing to update the AURORA model inputs for these most current thermal plant operating characteristics. PSE urges the Commission to reject ICNU's power cost adjustment. If the Commission were to adopt ICNU's adjustment, however, PSE recommends the Commission order that the AURORA model be updated to reflect all the current thermal operating assumptions.

J. Transmission Reassignment Sales

Q. Does PSE agree with ICNU's power cost adjustment for sales of excess transmission?

A. Yes. ICNU provided an adjustment to reduce power costs $1.1 million to reflect the most recent twelve months information through July 31, 2011. Exhibit No.___(MCD-1CT) at page 6, lines 6-16. Although PSE agrees with ICNU's proposal to set the credit for the sales of excess transmission revenues equal to the most recent twelve months, PSE, however, proposes to use transmission reassignment sales for the most recent twelve months (i.e., through November 30, 2011). Accordingly, PSE recommends an increase in transmission reassignment sales to approximately $3.0 million for the rate year; an increase of $1.2 million from those presented in PSE's supplemental filing.

Q. Why does PSE agree with ICNU's adjustment to transmission revenues?

A. As I noted in my prefiled direct testimony, PSE had recently obtained the right to reassign excess Bonneville Power Administration ("BPA") Point-to-Point ("PTP") transmission rights and developed a simple methodology to determine the level of excess PTP transmission to be available for sale in the rate year. The methodology appeared reasonable as the calculated amounts were in line with PSE's actual revenues from the sales of excess transmission. During the course of this proceeding, however, PSE's sales of excess transmission have been higher than this calculation determined. At this time, PSE accepts ICNU's approach, but will continue to review and analyze methods to accurately forecast these excess transmission sales revenues to ensure they reflect PSE's rate year portfolio.

K. Transmission Capacity

Q. Please describe Commission Staff's proposed adjustment for transmission capacity.

A. Commission Staff inappropriately removes the cost of PSE's renewal for 23 MW of cross-Cascades transmission capacity from rate year power costs. Commission Staff erroneously asserts that "PSE has made no explicit showing of benefits, or reduced costs, related to the acquisition of this firm transmission capacity." *See* Exhibit No. ___(APB-1CT) at page 22, lines 7-9. This assertion ignores my prefiled direct testimony that this transmission capacity provides PSE the ability to purchase short-term resources at the Mid-C trading hub and reduces PSE's transmission need.

Q. Was PSE's renewal of the transmission capacity a valuable and reasonable business decision?

A. Yes. PSE relies on existing firm BPA transmission contracts from Mid-C to PSE's system to meet its capacity need. PSE uses this transmission to make short-term market purchases at Mid-C to serve PSE's load – these short-term market purchases are referred to in the 2009 IRP as "Short Term Resources". When PSE elected to renew 23 MW of firm BPA transmission for a five-year term, PSE increased its Short Term Resources by 23 MW and reduced its capacity need by 23 MW starting in 2012 through 2015.

In PSE's 2010 Request for Proposal process, PSE concluded that short-term year-round index energy purchases delivered at PSE's system would be an effective mechanism for meeting its near-term capacity need given the current resource options. By extending this transmission contract, PSE provides a mechanism for additional winter season energy purchases at Mid-C to count in meeting PSE's existing capacity need. As compared to the other resource alternatives in the 2010 Request for Proposal, the extension of this transmission contract is a most cost effective way to meet PSE's near-term capacity need on a portfolio benefit ratio basis as well as on a total portfolio cost basis.

Moreover, regional transmission constraints limit long-term firm transmission availability from resources east of the Cascades to load west of the Cascades. PSE's transmission system does not have any additional long-term firm transmission capacity across the Cascades. BPA, the only other cross-Cascades transmission provider, has placed its transmission evaluation process (called the Network Open Season) on hold. Therefore, the renewal of 23 MW of cross-Cascades meets PSE's near-term needs for long-term firm capacity across the Cascades to the Mid-C market. PSE proposes that the Commission reject Commission Staff's $0.4 million adjustment to power costs.

L. Chelan PUD Contract Costs

Q. Please describe the power cost adjustment proposed by ICNU with respect to PSE's contract with Chelan PUD for the purchase of output from the Rocky Reach and the Rock Island Projects.

A. ICNU erroneously argues that PSE's payment obligations for the Capital Recovery charge ("CRC") and Debt Reduction Charge ("DRC") under the contract with Chelan PUD should be reduced to the minimum value of 25 percent and 2.5 percent, respectively. ICNU proposes a reduction to power costs of $1.9 million and $0.8 million, respectively. Exhibit No. ___(MCD-1CT) at page 9, line 6, through page 10, line 12. In addition, ICNU requests removal of the annual rate increase of 2.5 percent for the Chelan Transmission Revenue Requirement after 2011, which reduces power costs $0.1 million. *Id*. at page 10, lines 13-18. In total, ICNU reduces the Chelan PUD contract costs by $2.8 million. *Id*. at page 10, lines 19-20. ICNU provided no support for this argument. Chelan PUD Board's approval of a recommendation to establish the CRC and DRC at 50 percent and 3.0 percent, respectively, effective January 1, 2012 and a letter from Chelan PUD which states that rate will be used through 2013, is provided in Exhibit No. ___(DEM-12). Therefore, PSE's proposed adjustment appropriately reflects the Chelan PUD decision and PSE recommends that the Commission reject ICNU's $1.9 and $0.8 million adjustments.

Q. Please explain what an escalation factor represents and why the Company uses it.

A. When preparing budgets, it is reasonable to assert that costs will be typically higher in the next fiscal period, due to rising prices. The GDP deflator captures the fluctuations for the costs of a basket of goods, year over year, which is referred to as inflation. When calculating an estimated inflation factor over the years 2006-2010, the average is about 2.2 percent. The World Bank publishes United States GDP deflator data as follows:

Table 8. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
GDP Deflator

World Bank Inflation GDP Deflator	2006	2007	2008	2009	2010	5 Yr Avg
United States	3.3%	2.9%	2.2%	1.8%	0.8%	2.2%

The GDP deflator is known and measurable. It is reasonable to apply a 2.5% inflation factor to the Chelan transmission costs. Subsequent to PSE's Supplemental Filing, under PSE's new contract with Chelan, it was determined that Chelan's transmission costs will be updated on an annual basis every July 1st, rather than the January 1st date included in the Supplemental Filing. Moving the 2.5% escalator to July 2012 reduces power costs $.01 million.

Q. Have there been other changes to the Chelan PUD contract costs during this proceeding?

A. Yes. As discussed below, PSE's updated rate year power costs reflect updated budget information for all of the Mid-C contracts.

M. Chelan Capacity Reservation Charge Amortization

Q. Please explain Public Counsel's proposed adjustment to rate year power costs.

A. As noted in my prefiled direct testimony, rate year power costs include changes associated with the new Chelan PUD contract, which include $7.1 million for the amortization of the Chelan PUD contract $89 million capacity reservation charge. *See* Exhibit No. ___(DEM-1T) at page 54, lines 3-14. Public Counsel argues that PSE incorrectly calculated the deferral and proposes to remove $0.9 million from the rate year amortization expense to reflect their "correction". Exhibit No.___(ACC-1T) at page 35, line 13, through page 38, line 21. As discussed in the Prefiled Rebuttal Testimony of John H. Story, Exhibit No. ___(JHS-18T), Public Counsel's argument is unsubstantiated and the Commission should reject Public Counsel's adjustment to rate year amortization expense.

N. Colstrip Units 1 and 2 Capacity Reservation Payment Amortization

Q. Please describe Commission Staff's proposed adjustment to the amortization of the costs associated with the Colstrip 1 and 2 capacity reservation payment.

A. Commission Staff proposes to amortize the $5 million dedication fee for the coal supply contract for Colstrip Units 1 and 2 over a ten-year period rather than the nine-year period warranted under the contract terms. This proposal reduces power costs by $0.1 million. Exhibit No. ___(RCM-1T) at page 15, line 5, through page 16, line 12. Please refer to the Prefiled Rebuttal Testimony of John H. Story, Exhibit No. ___(JHS-18T) for a discussion of why this proposed adjustment should be rejected by the Commission.

O. Lower Snake River Transmission Credits

Q. Is Commission Staff's adjustment to power costs for LSR transmission credits correct?

A. No. The transmission expense reduction related to the LSR Phase 1 transmission credits should reflect the most current amortization schedule and the updated in-service dates for LSR Phase 1. The schedule Commission Staff witness Mr. Buckley uses for his adjustment to the LSR transmission credits for the rate year was updated by PSE in its response to Staff Data Request No. 195 that was submitted on November 22, 2011. Mr. Story discusses why Mr. Buckley's $0.8

million adjustment is duplicative to other Commission Staff adjustments and should be denied. While Commission Staff witness Mr. Martin uses the correct schedule in his adjustment for these prepaid transmission deposits, he double counts Mr. Buckley's adjustment. Mr. Buckley's $0.8 million adjustment is duplicative and should be rejected by the Commission. PSE has increased rate year transmission credits by $2.1 million to reflect the current amortization schedule, which is discussed in the Prefiled Rebuttal Testimony of John H. Story, Exhibit No. ___(JHS-18T). In addition, PSE has reflected a $0.1 million reduction in rate year transmission costs to reflect updated LSR Phase I information and prices. PSE has reduced rate year transmission costs a total of $2.2 million.

P. Other Adjustments

Q. Are there any other adjustments made by Commission Staff or ICNU?

A. Yes. ICNU has used a single AURORA model run to support its rate year power costs rather than the average of the 70-years of AURORA model runs. ICNU did not discuss this $1.1 million reduction to rate year power costs in their testimonies, so it appears to have been an inadvertent error. PSE proposes the Commission order that rate year power costs be based on an average of the 70-years of AURORA model runs and remove ICNU's $1.1 million adjustment. There are no other adjustments proposed by Commission Staff.

Q. Gas Price Update

Q. What is PSE's position with respect to the proposals of ICNU and Commission Staff to update rate year power costs with more recent gas prices?

A. PSE has consistently promoted the establishment of rate year gas prices based on forward prices as close as possible to the beginning of the rate year, regardless of whether gas prices were increasing or decreasing. ICNU proposes to reduce power costs by approximately $26.7 million. Exhibit No. ___(DWS-1T) at page 5, line 18, through page 7, line 20. Commission Staff proposes to reduce power costs by approximately $10.0 million. Exhibit No. ___CT(APB-1CT) at page 29, line 5, through page 31, line 13. PSE urges the Commission reject both adjustments and order PSE to update rate year power costs with more recent gas prices as discussed in further detail below.

IV. REBUTTAL OF PRODUCTION OPERATIONS AND MAINTENANCE ADJUSTMENTS

Q. What adjustments are Commission Staff and ICNU proposing be made to production O&M expenses?

A. Both ICNU and Commission Staff propose adjustments to production O&M as shown in Table 9 below. Please refer to the Prefiled Rebuttal Testimony of Wayne R. Gould, Exhibit No. ___(WRG-1T), for PSE's discussion on ICNU's and Commission Staff's production O&M proposals.

Table 9. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
Intervenor Production O&M Adjustments
($ in Millions)

Production O&M Adjustments	ICNU	Commission Staff
Frederickson, Fredonia, Sumas and Mint Farm	($7.1)	-
Other Production O&M	($1.3)	($0.7)
Non-Contract Major Maintenance	-	($3.5)
Jackson Prairie Agreement	-	($0.3)
Major Maintenance Amortization	-	($1.1)
Total Intervener Adjustments	($8.4)	($5.6)

Q. Are PSE's adjustments to production O&M expenses in this proceeding consistent with current regulatory precedent?

A. Yes. PSE's treatment of production O&M expenses in this proceeding is consistent with current regulatory precedent. As noted in my prefiled direct testimony, PSE consistently applies a very logical approach to determining rate year production O&M expenses, which follows Commission-approved methodologies from the 2009 GRC[4]:

- PSE Managed Resources = Test year production O&M costs and
- PSE Shared Resources = Third party rate year budgets.

In this proceeding, PSE has also included known and measurable escalation clauses for its wind facilities' service and royalty contracts in its rate year production O&M costs.

[4] *See WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 & UG-090705, Order 11 at paragraphs 159 & 162 (Apr. 2, 2010).

ICNU erroneously suggests that PSE's "treatment of production O&M expenses is inconsistent between resources [and] for some resources, such as Colstrip, the Company uses projected budgets for the rate year." *See* Exhibit No. ___(DWS-1CT) at page 11, lines 5-6. This statement fails to recognize that PSE applied the methodology used for as long as I can recall, which is the same as that approved by the Commission in its last general rate proceeding for rate year production O&M expenses:

> For Colstrip, the Company argues the rate year costs provided by the plant owner, PPL-Montana, should be used. According to the Company, these costs have been reviewed and approved by the majority of owners and such costs have been included in the last six rate cases." (par 159).

WUTC v. Puget Sound Energy, Inc., Dockets UE-090704 & UG-090705, Order 11 at paragraph 159 (Apr. 2, 2010).

Q. Does PSE agree with the adjustments to production O&M proposed by ICNU and Commission Staff?

A. No. PSE recommends that the Commission reject ICNU's proposed production O&M adjustments. PSE recommends that (i) the Commission accept Commission Staff's proposed production O&M adjustments that update the rate year costs associated with the Jackson Prairie Storage Agreement and (ii) the Commission reject Commission Staff's other proposed production O&M adjustments. Please see the Prefiled Rebuttal Testimony of Wayne R. Gould,

Exhibit No. ___(WRG-1T), for a discussion of PSE's response to ICNU's and Commission Staff's production O&M proposed adjustments.

Q. What is the adjustment for the Jackson Prairie Storage Agreement?

A. Commission Staff proposes to update the rate year rental fees associated with the Jackson Prairie Storage Capacity Agreement ("JP Agreement") between PSE's core gas book and PSE's power book to reflect the current cost of the JP Agreement. PSE's filing retained the test year level of costs for the JP Agreement because its price is re-set annually and the current contract price will be updated before the start of the rate year, on April 1, 2012. In this regard, PSE did not consider using the current contract cost rather than the test year cost to be a known and measurable adjustment. Please see the Prefiled Rebuttal Testimony of Mr. R. Clay Riding, Exhibit No. ___(RCR-4T), for further information. PSE, however, while not agreeing to Commission Staff's argument about fixed versus variable cost designation for PCA purposes, the Company agrees to Commission Staff's price adjustment and has reduced rate year power costs $0.3 million.

V. OTHER UPDATES TO RATE YEAR POWER COSTS

A. Mid-C Contract Costs

Q. Please describe the updated power cost adjustments proposed by PSE with respect to the Mid-C projects.

A. PSE has several contracts for the purchase of output from certain Mid-C hydroelectric projects. Specifically, PSE has contracts with the following public utility districts for the purchase of output from the following projects:

(i) with Public Utility District No. 1 of Chelan County, Washington ("Chelan PUD") for output from the Rocky Reach Project and the Rock Island Project;

(ii) with Public Utility District No. 2 of Grant County, Washington ("Grant PUD") for output from the Wanapum Project and the Priest Rapids Project; and

(iii) with Public Utility District No. 1 of Douglas County, Washington ("Douglas PUD") for output from the Wells Project.

PSE's contracts provide, in general, that it pay its contracted portion of the operations and debt expenses of the respective hydroelectric projects in return for a specified portion of the outputs of the projects. Projected rate year power costs represent the most recent budget or forecast information from these public utility districts. PSE has traditionally updated these costs in determining final projected rate year power costs. During this proceeding, PSE received updated budget information from each of the above PUDs which was provided to all parties, noting updates would be provided in subsequent power cost updates.

Accordingly, PSE proposes to include an additional $0.4 million in projected rate year power costs to reflect the updated information for the Mid-C contracts.

Q. What is the projected rate year power cost change related to the Rock Island Project and the Rocky Reach Project?

A. Chelan PUD has provided final budgets during the course of this proceeding for the Rock Island and the Rocky Reach Projects. These budgets represent the best estimate of the costs associated with PSE's portion of the projected rate year costs for the Rock Island and the Rocky Reach Projects and the amounts in these budgets decrease rate year power costs by $0.7 million. In addition, rate year power costs have been reduced $1.7 million to better reflect the contract terms of the new contract for Chelan PUD's Rocky Reach Project, which became effective November 1, 2011. In total, PSE's costs for the Chelan PUD contract have been reduced $2.4 million from the projected rate year power costs provided in PSE's supplemental filing dated September 1, 2011

Q. What is the projected rate year power cost change related to the Priest Rapids Project and the Wanapum Project?

A. Grant PUD has also provided final budgets during the course of this proceeding for the Priest Rapids Project and the Wanapum Project. PSE's forecast $2.0 million increase in the Grant PUD contract costs are directly attributed to the results of the auction dated November 4, 2011, a decline in Grant PUD's 2012 load forecast and an update in the 2013 forward marks which lowered the forecast auction revenue. These cost increases were mitigated by a reduction in Grant PUD's 2012 budget and the decline to their 2012 load forecast which simultaneously increased all purchaser's share of the Priest Rapids Project output. The decline in Grant PUD's 2012 load forecast caused PSE's Priest Rapids Project share for 2012 to increase from 0.64 percent to 0.90 percent, thereby increasing PSE's rate year hydro generation 11,558 MWhs (net of obligations to return power under the Canadian Entitlement Agreement) and lowering power costs approximately $0.4 million. These budgets represent the best estimate of the costs associated with PSE's portion of the projected rate year costs for the Priest Rapids Project and the Wanapum Project and increase the projected rate year power costs provided in PSE's supplemental filing dated September 1, 2011, by approximately by $1.6 million.

Q. What is the projected rate year power cost change related to the Wells Project?

A. Douglas PUD has also provided a final budget for the Wells Project. These budgets represent the best estimate of the costs associated with PSE's portion of the projected rate year costs for the Wells Project. This update increases the projected rate year power costs provided in PSE's supplemental filing dated September 1, 2011 by $0.1 million. In addition, PSE updated the forecast credit under the 1989 Settlement Agreement with Douglas PUD based upon the preliminary annual adjustment received mid-September 2011. This update increases the projected rate year power costs provided in PSE's supplemental filing dated September 1, 2011, by approximately $1.0 million.

B. Gas Price Update

Q. What natural gas prices are included in the rebuttal power costs?

A. PSE used a three-month average of daily forward market gas prices for the rate year for each trading day in the three-month period ending December 8, 2011. PSE input these data and the rate year fixed-price short-term power contracts in place at December 8, 2011, into the AURORA model for each of the months in the rate year. This is the same methodology as described in my prefiled direct testimony, except that it uses the more recent three-month period described above.

For purposes of comparison, the updated average price at Sumas for the rate year is $4.07/MMBtu, which is $0.72/MMBtu lower than the average price of $4.79/MMBtu used in PSE's supplemental filing on September 1, 2011.

Q. Please explain the change to forecast power costs caused by the update to rate year gas prices.

A. The rate year power costs were decreased by $12.0 million to reflect forecast gas prices at December 8, 2011. This routine update is methodical and includes updating the AURORA model for the more recent gas prices and for the fixed-price short-term rate year power contracts in place at the pricing date. In addition, the Not-in-Models costs have been updated to reflect the updated forecast gas prices, the updated AURORA modeled power prices, the more recently dated fixed-price short-term natural gas contracts and the more recently dated short-term power contracts.

C. Colstrip Cost Update

Q. Please describe the power cost and production O&M adjustments proposed by PSE with respect to the Colstrip units.

A. PSE has updated production O&M costs and the maintenance outage dates for the Colstrip units to reflect the most recent PPL-Montana Business Plans and maintenance schedules approved by the Colstrip owners. These updates decrease the projected rate year production O&M costs by $2.6 million from the projected rate year production O&M costs provided in PSE's supplemental filing dated September 1, 2011.

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PSE also updated the Colstrip fixed and variable costs to reflect the approved PPL-Montana Business Plans and the approved Annual Operating Plans from Western Energy, the coal supplier. The Colstrip Unit 1 maintenance outage in 2012 will start on [redacted] rather than [redacted] with no change to the [redacted] duration. This removes [redacted] of outage from the rate year and increases Colstrip Unit 1 energy production during the rate year. This update decreased power costs included in Not In Models by $0.7 million and the variable costs per the AURORA model by $0.9 million. Total rate year power costs for Colstrip have decreased $1.6 million from those provided in PSE's supplemental filing.

Q. Has this updated cost information been provided to parties during this proceeding?

A. Yes, PSE provided this updated information during this proceeding in response to data requests from Sierra Club.

D. Production O&M Summarize

Q. Is PSE providing an update to the projected rate year production O&M costs filed in its supplemental filing dated September 1, 2011?

A. Yes. As discussed above, PSE is proposing to update rate year production O&M costs to reduce costs by (i) $2.6 million for the Colstrip units and (ii) $0.3 million to accept Commission Staff's adjustment for the Jackson Prairie Agreement.

VI. UPDATED RATE YEAR POWER AND PRODUCTION O&M COSTS

A. Updated Projected Production O&M Costs

Q. What are PSE's updated projected rate year production O&M costs?

A. PSE's updated projected rate year production O&M costs are $134.7 million, a decrease of $2.9 million from the $137.6 million of projected rate year production O&M provided in PSE's supplemental filing dated September 1, 2011. Please see Exhibit No. ___(DEM-13) for the updated rate year production O&M costs. Please see the Prefiled Rebuttal Testimony of Wayne R. Gould, Exhibit No. ___(WRG-1T), for a detailed discussion regarding production O&M.

B. Updated Projected Rate Year Power Costs

Q. What are PSE's updated projected total rate year power costs, including updated projected production O&M costs?

A. PSE's updated projected total rate year power costs are $825.8 million, a decrease of $18.0 million from those provided in PSE's supplemental filing. PSE's updated projected total rate year power costs, including updated projected production O&M and other costs, are $961.9 million, a decrease of $20.9 million from those provided in PSE's supplemental filing dated September 1, 2011.

Please see Exhibit No. ___(DEM-12C) for the updated projected total rate year power costs, including projected production O&M costs, as compared and reconciled with those provided in PSE's supplemental filing dated September 1, 2011.

Table 10 below also provides a summary of the updated projected total rate year power costs, including updated projected production O&M and other costs, as reconciled with those provided in PSE's supplemental filing dated September 1, 2011.

Table 10. Puget Sound Energy, Inc.
2011 General Rate Case Rebuttal
Updated Power Cost Forecast Reconciliation
($ in Thousands)

	Power Costs	Prod'n O&M	Other	Total	Load
Supplemental Filing	**$843,789**	**$137,606**	**$1,420**	**$982,815**	**23,172,444**
Gas Price Update to 3-mo average at 12.8.11	($11,977)			($11,977)	
Colstrip Coal Cost and O&M Update	($1,564)	($2,627)		($4,191)	
Transmission (Primarily LSR Credits)	($2,168)			($2,168)	
Transmission Reassignment Sales	($1,218)			($1,218)	
Mid C: Chelan, Grant, Douglas Updated Budgets	$359			$359	
Gas Pipeline Fixed Charge Escalation	($978)			($978)	
Peak Planning	($482)			($482)	
Jackson Prairie Storage Rent		($304)		($304)	
Total Updates	**($18,028)**	**($2,930)**	**$0**	**($20,958)**	**-**
Total Rebuttal Power Costs & Production O&M	**$825,761**	**$134,676**	**$1,420**	**$961,857**	**23,172,444**

Q. Should the Commission require an update to projected rate year power costs before the new rates go into effect?

A. Yes. The Commission should require an update to projected rate year power costs. The projected rate year power costs should be updated to reflect more recent gas prices, just prior to rates going into effect and in the manner with which they have been updated in the past and in this proceeding, so that they reflect the best estimate of the costs to be incurred in the rate year. As in past cases, this update should also include an update to the short-term fixed-price power contracts that are an AURORA input and the other index-based power and all gas for power contracts that are an adjustment included in the "Not in Models" calculation. In addition, some "Not in Models" adjustments are dependent on the AURORA generation and prices. These adjustments update automatically in the MS Excel files whenever a new AURORA model run download is included in the files.

Q. What is the current three-month average rate year gas price?

A. The current three-month average rate year gas price as of January 4, 2012 was $3.84 per MMBtu and the average rate year gas price as of January 4, 2012 was $3.48 per MMBtu. The December 8, 2012 three-month average rate year gas price as of December 8, 2012, included in the current projected rate year power cost forecast is $4.07 per MMBtu.

VII. CONCLUSION

Q. Please summarize your testimony.

A. PSE has carefully considered all of the power cost and production O&M adjustments proposed by ICNU, Commission Staff and Public Counsel, as discussed in PSE's prefiled rebuttal testimonies.

PSE urges the Commission to (i) adopt PSE's projected rate year power and production O&M costs, based in some part on the adjustments proposed by ICNU and Commission Staff to which PSE can agree and on updated information; and (ii) require rate year power costs to be updated with more recent gas prices in the manner noted above.

Q. Does that conclude your prefiled rebuttal testimony?

A. Yes.